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Docket Number 50-346

License Number NPF-3

Serial Number 2989

November 3, 2003

United States Nuclear Regulatory Commission
Document Control Desk
Washington, D. C. 20555-0001

Subject: Request for Additional Information Regarding the 2002 Steam Generator Tube Inspections (TAC No. MB9541)

Ladies and Gentlemen:

By letters dated March 22, 2002 (Serial Number 2771), and March 31, 2003 (Serial Number 2944), the FirstEnergy Nuclear Operating Company (FENOC) reported the results of the Davis-Besse Nuclear Power Station (DBNPS) 2002 steam generator tube inspections. On July 28, 2003, by facsimile the NRC provided FENOC with a request for additional information regarding the DBNPS 2002 steam generator inspections. This request was also provided in a letter from the NRC dated September 23, 2003 (Log Number 6119). The response to this request for additional information is provided in Attachment 1 to this letter.

Should you have any questions or require additional information, please contact Mr. Kevin L. Ostrowski, Manager - Regulatory Affairs, at (419) 321-8450.

Very truly yours,

Lew W. Myers

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Attachments

cc: Regional Administrator, NRC Region III
J. B. Hopkins, DB-1 NRC/NRR Senior Project Manager
C. S. Thomas, DB-1 NRC Senior Resident Inspector
Utility Radiological Safety Board

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Request for Additional Information
Davis-Besse Nuclear Power Station 2002 Steam Generator Inspection
TAC No. MB9541

1. *In your letters dated March 22, 2002, and March 31, 2003, the inspections for steam generators (SGs) 1 and 2 in Tables 1 and 4, respectively, were summarized. Please summarize the inspection results for each inspection category. For example, for each inspection category (dents, dings, sleeves, lane/wedge region, upper tubesheet expansion transition, sludge zone, bobbin indications, etc.), discuss the results of the inspection including the nature (axial primary water stress corrosion cracking (PWSCC), groove intergranular attack (IGA), circumferential PWSCC, etc.) and severity (length, depth, voltage) of each indication detected. If indications were found, discuss the technical basis for the scope of the inspections (i.e., if a flaw was located in a 2 volt dent, discuss the basis for not expanding the scope of the rotating probe examination to include all dents). In your response, address how the indications were detected (e.g., bobbin coil, rotating probe, bobbin and rotating probe, etc.).*

Background

The Davis-Besse Nuclear Power Station (DBNPS) Thirteenth Refueling Outage (13RFO) commenced on February 16, 2002. During this outage routine inservice inspection of the steam generators was performed. This is a summary of the steam generator activities performed during this outage.

The DBNPS had operated approximately 15.8 effective full power years as of the 13RFO. Prior to 13RFO, 436 tubes in steam generator 2A had been plugged and 104 tubes in steam generator 1B had been plugged, leaving a total of 30,374 inservice tubes. At the time of shutdown for 13RFO, less than 1 gallon per day primary-to-secondary leakage was observed.

Steam generator inspection activities were performed under the Steam Generator Management Program. The following inspection activities of the steam generators were performed:

1. Inspection of new re-rolls.
2. Inspection of all in-service tubes and sleeves by a bobbin coil.
3. Inspection of 62 percent of the sleeve roll expansions by a plus point coil.
4. Inspection of 57 percent of the tube upper roll expansions by a plus point and pancake coil.

5. Inspection of all of the non-stress-relieved tube roll expansions–factory re-rolls by a plus point and pancake coil.
6. Inspection of 60 percent of the hot leg roll plugs by a plus point coil.
7. Inspection of the tubes bordering the sleeve region by a plus point and pancake coil.
8. Inspection of all of the flaw-like indications reported from bobbin by a plus point and pancake coil.
9. Inspection of the dent indications, including all those located above the 14th tube support plate and a 60 percent sample of the remaining population by a plus point and pancake coil.
10. Inspection of 500 tubes at the sludge pile region of the lower tubesheet in each steam generator by a plus point and pancake coil.
11. Inspection of plugged tubes per the Three Mile Island (TMI) severance tube event.
12. Inspection of all welded tube plugs by qualified VT-1.

Periphery Tubes

Technical Specification 4.4.5.7 requires the steam generators to have a totally separate examination performed on at least 150 outer most periphery tubes in the vicinity of the secured internal Auxiliary Feedwater header. This examination is to inspect for changes in the gap between the tubes and the secured internal Auxiliary Feedwater (AFW) header to verify the header has not moved.

100% of the inservice periphery tubes were inspected for the AFW header gap in 13RFO.

SG 2-A: There were 12 AFW header indications for which gap measurements were performed. All twelve were measured with gaps larger than 0.250 inches. There was 1 weld splatter indication. The weld splatter was from the prior repair of the AFW header.

SG 1-B: There were 3 AFW header indications for which gap measurements were performed. All three were measured with gaps larger than 0.250 inches. There were 25 weld splatter indications.

No indication of movement in the secured internal AFW header was observed.

Sleeve Border Region Inspection

To verify that the Once-Through Steam Generators (OTSGs) are adequately sleeved, per the DBNPS response to Generic Letter 95-03, a one tube wide border of un-sleeved tubes in service around the lane/wedge region of sleeved tubes were examined with rotating coil probes to confirm that the sleeved region is still adequately bounded. This examination is for detecting whether high cycle fatigue degradation is occurring in the un-sleved tubes. The 15th tube support plate and upper tubesheet secondary face areas of each tube were examined. The 15th tube support plate was examined from 1 inch below to 1 inch above. The upper tubesheet secondary face was examined from 1inch below to 4 inches into the tubesheet.

A total of 165 tubes that are classified as Sleeve Border locations were inspected with the plus point/pancake eddy current examination technique at the 15th tube support plate and the upper tube sheet secondary face (85 tubes in SG 2-A and 80 tubes in SG 1-B).

No fatigue degradation of these tubes was discovered in either OTSG during 13RFO.

Non-Stress Relieved Roll Transition Inspections

Per the DBNPS response to Generic Letter 95-03, each in service tube-to-tubesheet expansion transition which was not stress relieved (rolled into the tube sheet following vessel annealing, including any re-rolls) that was not previously sleeved or plugged was inspected with plus point and pancake coil probes. This includes transitions in both the upper and lower tubesheets. Based on information from Framatome Technologies Incorporated (FTI) on the original OTSG fabrication records, tubes A-110-59, A-127-77, B-97-101, B-98-112, and B-74-85 have non-stress relieved transitions in the upper tubesheet. Tube A-127-67 has a non-stress relieved joint in the lower tube sheet. No new repair rolls were in service at the time of the 13RFO inspection.

No degradation of the non-stress relieved roll transitions were observed during 13RFO.

Roll Transition and Tube End Inspections

With discovery of upper tube end primary water stress corrosion cracking (PWSCC) in Babcock & Wilcox (B&W) OTSGs, a general upper tubesheet tube roll and tube end inspection was performed with motorized rotating coil (MRC) probes. Since the 11RFO inspection included 21% of the in service tubes and the 12RFO included 20% of all the tubes, the 13RFO inspection was established at 59% of the inservice tubes to complete a 100% inspection over a three cycle period.

Escalation of the roll expansion inspection or the tube end inspection to a 100% sample was to occur if 1% or more (C-3 inspection category) of the expansions or transitions were found to be defective. A C-3 result would also make it necessary to perform a sample in the lower tube sheet region for the same C-3 condition. An exception to the EPRI Steam Generator inspection guideline had been established to justify an inspection expansion based on Technical Specifications rather than on discovery of a single PWSCC defect based on a leakage assessment. A C-3 inspection category did not result for this inspection during 13RFO.

SG 2-A had 39 crack-like indications in 39 tubes from the upper roll transition (URT) examination. Thirty-five of these indications were axial cracks located near the tube end (Single Axial Anomaly (SAA) and Multiple Axial Anomaly (MAA)). Three of these indications were circumferential indications located near the tube end at the heat affected zone of the tube end welds. The remaining indication was a PWSCC single axial indication (SAI) located in the expanded region of the tubing below the clad/carbon steel interface in the original roll joint in the upper tubesheet region in the steam generator.

SG 1-B had 6 crack-like indications and 2 volumetric indications in 8 tubes from the URT examination. The crack-like indications were all axially-oriented and located near the tube end (SAA and MAA). One of the volumetric indications (Tube B-65-58) was in the roll expansion and was on the inside diameter (ID) of the tube. This indication looked like a scrape where something may have been inserted into the tube at one time. The other volumetric indication was located in the tubesheet crevice just below the roll transition. All eight of these tubes were successfully re-rolled and, therefore, remain in service.

The tube end and roll indications observed during 13RFO are listed below.

DBNPS 13 RFO 2002										
Axial Tubesheet Roll Indications										
SG	Row	Tube	Ind	Volts	TSP	Inch1	Probe	Depth %TW (max.)	Ax Len	Deg. Mode
2A	63	78	SAI	2.38	UTE	-1.22	520PP	99	0.41	PWSCC
	520PP=Plus Point Probe			SAI=Single Axial Indication						

DBNPS 13 RFO 2002										
Circumferential Tube End Indications										
SG	Row	Tube	Ind	Volts	TSP	Inch1	Probe	Depth %TW (max.)	Circ Len	Deg. Mode
2A	45	120	SCI	1.02	UTE	-0.32	520PP	42	0.47	Tube End PWSCC
2A	63	1	SCI	1.95	UTE	-0.27	520PP	44	0.44	Tube End PWSCC
2A	117	108	SCI	0.47	UTE	-0.27	520PP	57	0.62	Tube End PWSCC
	520PP=Plus Point Probe			SCI=Single Circumferential Indication						

DBNPS 13 RFO 2002											
Volumetric Indications in Tubesheet Roll Area											
SG	Row	Tube	Ind	Volts	TSP	Inch1	Probe	Depth %TW (max.)	Ax Len	Circ Len	Deg. Mode
1B	65	58	MVI	0.92	UTE	-1.58	520PP	78	0.36	0.23	Mechanical ID
1B	99	26	SVI	0.12	UTE	-1.74	520PP	57	0.24	0.31	Volumetric IGA
	520PP=Plus Point Probe					SVI=Single Volumetric Indication					
						MVI=Multiple Volumetric Indication					

DBNPS 13 RFO 2002							
Tube End Axial Indications							
SG	Row	Tube	Ind	Volts	TSP	Inch1	Probe
2A	12	39	SAA	2.68	UTE	-0.27	520PP
2A	14	10	SAA	2.51	UTE	-0.30	520PP
2A	15	10	MAA	1.29	UTE	-0.32	520PP
2A	15	70	SAA	1.22	UTE	-0.33	520PP
2A	18	13	MAA	1.74	UTE	-0.28	520PP
2A	18	14	MAA	2.42	UTE	-0.16	520PP
2A	21	16	SAA	2	UTE	-0.14	520PP
2A	21	76	MAA	0.58	UTE	-0.20	520PP
2A	21	77	SAA	0.7	UTE	-0.34	520PP
2A	27	21	SAA	0.85	UTE	-0.30	520PP
2A	27	65	SAA	1.51	UTE	-0.28	520PP
2A	30	23	MAA	1.1	UTE	-0.29	520PP
2A	46	116	SAA	0.98	UTE	-0.28	520PP
2A	62	2	SAA	1.6	UTE	-0.21	520PP
2A	63	3	MAA	2.78	UTE	-0.23	520PP
2A	65	1	SAA	3.14	UTE	-0.24	520PP
2A	66	1	SAA	2.42	UTE	-0.26	520PP
2A	68	3	MAA	2.22	UTE	-0.16	520PP
2A	68	4	SAA	2.12	UTE	-0.25	520PP
2A	84	4	MAA	2.8	UTE	-0.21	520PP
2A	86	4	SAA	0.56	UTE	-0.27	520PP
2A	86	7	MAA	3.27	UTE	-0.25	520PP
2A	87	9	SAA	1.51	UTE	-0.27	520PP
2A	89	8	SAA	1.82	UTE	-0.22	520PP
2A	91	7	SAA	1.87	UTE	-0.33	520PP
2A	91	8	SAA	1.74	UTE	-0.21	520PP
2A	92	9	SAA	1.42	UTE	-0.40	520PP
2A	96	5	MAA	2.15	UTE	-0.38	520PP
2A	99	7	SAA	1.17	UTE	-0.41	520PP

2A	116	104	MAA	1.15	UTE	-0.25	520PP
2A	116	110	MAA	1.39	UTE	-0.27	520PP
2A	116	112	SAA	1.65	UTE	-0.24	520PP
2A	117	103	MAA	1.35	UTE	-0.24	520PP
2A	120	103	SAA	0.95	UTE	-0.31	520PP
2A	122	103	SAA	0.85	UTE	-0.23	520PP
1B	27	63	SAA	1.25	UTE	-0.26	520PP
1B	27	64	SAA	0.81	UTE	-0.3	520PP
1B	36	99	MAA	1.08	UTE	-0.28	520PP
1B	95	1	SAA	1.65	UTE	-0.39	520PP
1B	104	32	SAA	1	UTE	-0.25	520PP
1B	130	73	SAA	1.83	UTE	-0.34	520PP
	520PP=Plus Point Probe		SAA=Single Axial Anomaly				
			MAA=Multiple Axial Anomaly				

Sleeve Inspections

A 62% sample of all sleeve roll expansions was performed. The tubesheet and freespan expansions of the sleeve were examined with the plus point coil. All sleeves were also inspected full length by bobbin coil.

20% samples had been performed during each of the past two outages. This inspection scope was selected to complete a 100% sample in three cycles.

No sleeve degradation was discovered in either OTSG during 13RFO.

Dents at or above the 14th Tube Support Plate

The DBNPS inspected all reported dents (2.5 volt bobbin threshold) located at the 14th tube support plate and above.

SG 2-A had 18 (new and repeat) dents that were located at or above 14S. SG 1-B had 21 (new and repeat) dents that were located at or above 14S. New means dents that were reported for the first time.

There was a small voltage dent in Tube A-105-1 that was below the 2.5 volt reporting threshold for dents that required repair. This tube had an Non-Quantifiable Indication (NQI) reported from bobbin and was, therefore, inspected with a plus point probe as part of the Special Interest inspection. This dented location was confirmed as having a circumferential PWSCC indication from the plus point inspection. This dent is believed to be attributable to an alignment pin that was removed from the OTSG when stabilizing the abandoned internal Auxiliary Feedwater header in the early 1980s. This tube is directly in front of an alignment pin location and the dent is located approximately 17 inches above the 15th support plate coinciding with the pin location.

Four tubes in SG 1-B with dents above the 14th tube support were removed from service. One of these tubes was plugged for an indication unrelated to the dent. The other three tubes were plugged due to axial PWSCC indications in the dent. Two of these dents (Tubes B-63-128 and B-95-128) were associated with the AFW header.

All dent indications which resulted in repairs due to PWSCC were first reported as non-quantifiable indications (NQIs) by bobbin and were confirmed by plus point inspection.

All repaired dents were located above the 15^{th} support. The DBNPS has not been observing active dent cracking below the 14^{th} support. All dents below the 14^{th} support have been inspected with rotating coil over the past 60 EFPM (3 fuel cycles). Additionally all dent cracking observed during 13RFO was first identified as NQIs by bobbin inspection adding confidence to the detection of this damage mechanism.

Axial and circumferential dent indications observed during 13RFO are listed below.

DBNPS 13 RFO 2002										
Axial Dent Indications										
SG	Row	Tube	Ind	Volts	TSP	Inch1	Probe	Depth %TW (max.)	Ax Len inches	Deg. Mode
1B	63	128	SAI	0.37	UTS	-13.71	510UL / 520PP	14	0.21	Dent (3.58 volt)
1B	95	128	SAI	0.28	UTS	-14.22	510UL / 520PP	0	0.18	Dent (3.0 volt)
1B	123	66	SAI	0.24	UTS	-4.42	510UL / 520PP	12	0.58	Dent (4.16 volt)
	510UL=Bobbin Coil			SAI=Single Axial Indication						
	520PP=Plus Point Probe									

DBNPS 13 RFO 2002										
Circumferential Dent Indications										
SG	Row	Tube	Ind	Volts	TSP	Inch1	Probe	Depth %TW (max.)	Circ Len inches	Deg. Mode
2A	105	1	SCI	0.56	15S	17.61	520PP	38	0.14	Dent (1.97 volt)
	520PP=Plus Point Probe			SCI=Single Circumferential Indication						

Dents below the 14th Tube Support Plate

The DBNPS inspected a 60% sample of new and repeat dents below the 14th tube support plate during 13RFO. SG 2-A contained a total of 208 dents and SG 1-B contained 170 dents below the 14th tube support plate.

No dent degradation was discovered during 13RFO below the 14th tube support plate.

Rolled Plug Inspections

Eddy Current examination of 60% of the Upper Tubesheet (UTS) B&W rolled plugs, and 100% of the UTS ABB/CE plugs was performed during the 13RFO. The mechanical plugs at the DBNPS are made of Alloy 690.

No indications were detected in the Upper Tubesheet rolled plugs during this examination.

Lower Tubesheet Examination

Due to the discovery of tube cracking that the bobbin coil may potentially not detect near the secondary face of the lower tube sheet in the sludge pile region, as was discovered at other OTSGs, the DBNPS inspected an area of the lower tube sheet that may potentially have degraded bobbin coil probability of detection (POD) with motorized rotating coil (MRC). This inspection was from 4 inches above to 16 inches below the secondary face of the lower tube sheet (LTS). Where the sludge height was greater than 4 inches above the LTS, the Rotating Plus Point Examination upper extent was verified to be above the sludge height.

The region inspected bounded the Oconee defined sludge pile region which was comprised of 2180 tubes. A 20% random sample of this region (436 tubes) was performed. An additional 64 tubes was randomly selected for inspection from an area surrounding the sludge pile region.

No indications were reported in either SG for this examination scope.

Wear Indications

SG 2-A had 288 tube support plate (TSP) wear indications (in 239 tubes) confirmed with plus point. All of the wear indications measured less than 40% through-wall (TW). Five wear indications in five different tubes were removed from service for other reasons. Therefore, 283 wear indications remained in service in 234 different tubes in SG 2-A. There were three wear indications reported at the 15th tube support plate (15S). The remaining 285 wear indications were located below the 15S. None of the wear indications at 15S are in periphery tubes and two of the indications at 15S were removed from service.

SG 1-B had 228 TSP wear indications (in 203 tubes) confirmed with plus point. All of the wear indications measured less than 40%TW. One wear indication was removed from service for other reasons. Therefore, 227 wear indications remained in service in 202 tubes in SG 1-B. There was one wear indication reported at 15S. The remaining 227 were located below the 15S. The wear indication at 15S is in Tube B-68-3 and is, therefore, close to the periphery of the tube bundle. This tube has a broached hole at 15S, i.e., it is not part of the peripheral tube locations that have drilled holes at the 15S.

The largest tube wear indications observed during 13RFO are listed below.

DBNPS 13 RFO 2002								
Top 10 Wear Calls By Depth								
SG	Row	Tube	Ind	Volts	TSP	Inch1	Probe	%TW (max.)
1B	122	104	WAR	0.72	10S	-0.58	520PP	36
1B	151	13	WAR	0.72	14S	-0.19	520PP	33
2A	147	36	WAR	0.52	10S	0.69	520PP	30
2A	150	27	WAR	0.5	10S	-0.66	520PP	29
1B	14	74	WAR	0.43	12S	-0.26	520PP	28
2A	16	2	WAR	0.47	13S	-0.69	520PP	28
1B	22	5	WAR	0.49	09S	0.62	520PP	28
2A	18	1	WAR	0.45	13S	-0.59	520PP	27
1B	115	114	WAR	0.48	07S	-0.55	520PP	27
1B	123	102	WAR	0.48	10S	-0.61	520PP	27
	520PP=Plus Point Probe							
	WAR=Wear Indication							

Volumetric Indications

As a result of the eddy current inspections there were 66 indications repaired in OTSG 2-A and 18 indications repaired in OTSG 1-B for volumetric intergranular attack (IGA). The majority of the confirmed indications were between the 3rd tube support plate and the 7th tube support plate and are attributable to a feedwater chemistry excursion which occurred in the mid-1980's. The appearance of new indications is somewhat variable as degradation grows to just over the detection level. Chemical cleaning at 12RFO is believed to have made this degradation more visible at 13RFO due to the removal of masking deposits. Hence, the number of indications in SG 2-A at 13RFO jumped from the previous inspection.

A 100% full-length bobbin exam was utilized during 13RFO; therefore, escalation of the inspection sample was not required.

The volumetric indications repaired during 13RFO are listed below.

DBNPS 13 RFO 2002											
Volumetric Indications (Except Tube Support Wear)											
SG	Row	Tube	Ind	Volts	TSP	Inch1	Probe	Depth %TW (max.)	Ax Len	Circ Len	Deg. Mode
2A	42	67	SVI	0.2	06S	-0.19	520PP	0	0.18	0.23	Volumetric IGA
2A	44	117	SVI	0.18	08S	-0.01	520PP	0	0.18	0.18	Volumetric IGA
2A	52	66	SVI	0.2	05S	0.29	520PP	14	0.12	0.29	Volumetric IGA
2A	64	51	SVI	0.19	04S	16.69	520PP	50	0.19	0.15	Volumetric IGA
2A	65	70	SVI	0.12	04S	9.16	520PP	49	0.09	0.12	Volumetric IGA
2A	65	70	SVI	0.13	04S	8.59	520PP	59	0.25	0.26	Volumetric IGA
2A	65	70	SVI	0.09	04S	7.34	520PP	44	0.25	0.29	Volumetric IGA
2A	65	73	SVI	0.11	04S	5.14	520PP	53	0.14	0.12	Volumetric IGA
2A	66	61	SVI	0.12	04S	13.58	520PP	57	0.23	0.23	Volumetric IGA
2A	67	52	SVI	0.15	04S	16.13	520PP	54	0.2	0.18	Volumetric IGA
2A	67	67	SVI	0.07	04S	10.12	520PP	56	0.41	0.29	Volumetric IGA
2A	68	51	SVI	0.21	04S	17.87	520PP	55	0.14	0.15	Volumetric IGA
2A	68	51	SVI	0.14	04S	14.04	520PP	55	0.14	0.15	Volumetric IGA
2A	70	63	SVI	0.11	04S	3.4	520PP	37	0.23	0.17	Volumetric IGA
2A	71	65	SVI	0.11	06S	15.97	520PP	53	0.18	0.12	Volumetric IGA
2A	71	65	SVI	0.06	06S	14.25	520PP	62	0.18	0.23	Volumetric IGA
2A	71	65	SVI	0.03	06S	13.73	520PP	59	0.2	0.23	Volumetric IGA
2A	71	65	SVI	0.04	06S	12.87	520PP	59	0.2	0.3	Volumetric IGA
2A	71	66	SVI	0.26	03S	0.44	520PP	40	0.22	0.23	Volumetric IGA
2A	71	72	SVI	0.13	04S	4.7	520PP	46	0.32	0.32	Volumetric IGA
2A	71	72	SVI	0.07	04S	3.12	520PP	52	0.18	0.23	Volumetric IGA
2A	71	72	SVI	0.04	04S	2.49	520PP	34	0.23	0.2	Volumetric IGA
2A	71	72	SVI	0.23	04S	1.51	520PP	49	0.22	0.12	Volumetric IGA
2A	74	68	SVI	0.08	04S	11.32	520PP	44	0.23	0.29	Volumetric IGA
2A	78	67	SVI	0.18	06S	4.97	520PP	57	0.21	0.23	Volumetric IGA
2A	78	67	SVI	0.1	06S	16.95	520PP	49	0.3	0.23	Volumetric IGA
2A	79	33	SVI	0.19	UTS	5.33	520PP	27	0.11	0.16	Volumetric IGA
2A	79	73	SVI	0.26	04S	12.05	520PP	37	0.1	0.18	Volumetric IGA
2A	79	73	SVI	0.15	04S	13.15	520PP	47	0.1	0.12	Volumetric IGA
2A	80	61	SVI	0.31	07S	0.13	520PP	0	0.18	0.17	Volumetric IGA
2A	80	73	SVI	0.1	04S	0.98	520PP	52	0.3	0.26	Volumetric IGA
2A	81	73	SVI	0.09	04S	11.93	520PP	59	0.3	0.26	Volumetric IGA
2A	82	30	SVI	0.32	08S	-0.18	520PP	23	0.19	0.12	Volumetric IGA
2A	82	74	SVI	0.17	04S	13.24	520PP	60	0.18	0.17	Volumetric IGA
2A	83	73	MVI	0.07	04S	9.68	520PP	47	0.18	0.23	Volumetric IGA
2A	83	75	SVI	0.21	04S	-0.36	520PP	0	0.18	0.17	Volumetric IGA
2A	84	73	SVI	0.24	04S	11.83	520PP	42	0.26	0.3	Volumetric IGA
2A	85	63	SVI	0.29	06S	0.23	520PP	0	0.23	0.29	Volumetric IGA

2A	85	69	SVI	0.12	04S	7.9	520PP	43	0.18	0.23	Volumetric IGA
2A	85	69	MVI	0.12	04S	10.16	520PP	58	0.18	0.17	Volumetric IGA
2A	85	69	MVI	0.19	04S	12.01	520PP	43	0.32	0.32	Volumetric IGA
2A	85	72	SVI	0.2	04S	13.8	520PP	41	0.18	0.18	Volumetric IGA
2A	86	61	SVI	0.04	04S	12.72	520PP	30	0.18	0.18	Volumetric IGA
2A	86	61	SVI	0.1	04S	11.35	520PP	53	0.13	0.12	Volumetric IGA
2A	87	92	SVI	0.19	05S	0.17	520PP	0	0.18	0.23	Volumetric IGA
2A	88	75	SVI	0.39	05S	-0.38	520PP	0	0.23	0.29	Volumetric IGA
2A	90	62	SVI	0.33	05S	-0.16	520PP	0	0.27	0.23	Volumetric IGA
2A	93	89	SVI	0.26	05S	0	520PP	11	0.12	0.18	Volumetric IGA
2A	95	6	SVI	0.22	UTS	9.3	520PP	45	0.19	0.12	Volumetric IGA
2A	97	13	SVI	0.14	UTS	8.44	520PP	40	0.19	0.17	Volumetric IGA
2A	97	40	SVI	0.19	05S	2.12	520PP	45	0.25	0.32	Volumetric IGA
2A	99	92	SVI	0.24	06S	-0.13	520PP	0	0.18	0.23	Volumetric IGA
2A	104	104	SVI	0.2	07S	-0.28	520PP	23	0.18	0.18	Volumetric IGA
2A	106	22	SVI	0.15	05S	13.29	520PP	57	0.13	0.17	Volumetric IGA
2A	106	38	SVI	0.16	05S	3.28	520PP	42	0.13	0.2	Volumetric IGA
2A	106	119	SVI	0.35	15S	17.73	520PP	32	0.12	0.23	Volumetric IGA
2A	117	64	SVI	0.12	05S	3.14	520PP	30	0.24	0.23	Volumetric IGA
2A	118	5	SVI	0.23	09S	-0.13	520PP	13	0.19	0.12	Volumetric IGA
2A	120	63	SVI	0.16	05S	2.39	520PP	52	0.18	0.18	Volumetric IGA
2A	120	63	SVI	0.09	05S	2.89	520PP	38	0.18	0.18	Volumetric IGA
2A	120	63	SVI	0.12	05S	2.63	520PP	40	0.18	0.18	Volumetric IGA
2A	125	79	MVI	0.22	05S	15.01	520PP	57	0.12	0.12	Volumetric IGA
2A	127	69	SVI	0.19	05S	6.25	520PP	54	0.12	0.18	Volumetric IGA
2A	134	60	SVI	0.15	05S	-0.27	520PP	0	0.18	0.23	Volumetric IGA
2A	135	21	SVI	0.21	05S	-0.27	520PP	7	0.15	0.12	Volumetric IGA
2A	141	36	SVI	0.42	04S	0.02	520PP	23	0.24	0.23	Volumetric IGA
1B	40	52	SVI	0.29	06S	0.1	520PP	36	0.18	0.18	Volumetric IGA
1B	65	58	MVI	0.92	UTE	-1.58	520PP	78	0.36	0.23	Mechanical ID
1B	65	62	SVI	0.21	04S	30.78	520PP	62	0.23	0.21	Volumetric IGA
1B	67	2	SVI	0.13	UTS	9.62	520PP	49	0.19	0.34	Volumetric IGA
1B	68	63	MVI	0.08	03S	23.86	520PP	47	0.23	0.21	Volumetric IGA
1B	68	63	MVI	0.09	03S	32.38	520PP	57	0.23	0.21	Volumetric IGA
1B	70	62	SVI	0.23	03S	28.8	520PP	48	0.23	0.21	Volumetric IGA
1B	72	59	SVI	0.08	04S	4.91	520PP	54	0.23	0.21	Volumetric IGA
.1B	73	62	SVI	0.13	04S	9.86	520PP	42	0.29	0.22	Volumetric IGA
1B	80	70	SVI	0.14	03S	38.11	520PP	55	0.17	0.16	Volumetric IGA
1B	83	66	SVI	0.25	03S	21.44	520PP	54	0.17	0.16	Volumetric IGA
1B	83	66	SVI	0.15	04S	1.33	520PP	50	0.12	0.11	Volumetric IGA
1B	89	54	SVI	0.27	06S	0.3	520PP	0	0.13	0.21	Volumetric IGA
1B	96	124	SVI	0.49	05S	0.29	520PP	24	0.18	0.24	Volumetric IGA
1B	99	26	SVI	0.12	UTE	-1.74	520PP	57	0.24	0.31	Volumetric IGA
1B	102	73	SVI	0.31	06S	0.07	520PP	11	0.23	0.24	Volumetric IGA
1B	130	93	SVI	0.15	15S	-4.22	520PP	0	0.22	0.24	Mechanical (AFH Repair)
1B	142	37	SVI	0.15	07S	0.03	520PP	24	0.14	0.18	Volumetric IGA
	520PP=Plus Point Probe					SVI=Single Volumetric Indication					
						MVI=Multiple Volumetric Indication					

Freespan ODIGA/SCC Indications

The 13RFO outage was the first observed occurrence at the DBNPS of the so called "groove IGA" (freespan axial outside diameter stress corrosion cracking/intergranular attack (ODSCC/IGA)) experienced by all other OTSG plants. A total of 4 indications in 4 tubes were observed in OTSG 1-B and 3 indications in 2 tubes were observed in OTSG 2-A. These indications occurred near the 15th tube support and upper tubesheet region of both OTSGs. This is the first discovery of this damage mechanism at the DBNPS, although inspections for this mechanism date back to 1998. Three of the indications were identified to have existed in previous bobbin inspections, but were only identified with the benefit of "look-back" knowledge because the previous data was below the detection threshold. The DBNPS staff believes that these indications may have developed in scratches caused during the manufacturing or tube installation process.

Another form of freespan axial ODSCC at the DBNPS is included in this category for convenience adding one additional indication in each OTSG. Axial coalescence of volumetric IGA degradation in the mid-bundle region is believed to have resulted in one additional tube in each OTSG having an indication classified as axial freespan cracking. From a structural viewpoint, these forms of freespan axial degradation are equivalent. Two axial IGA indications were detected near the 4th and 7th tube support plate intersections, respectively. These indications are believed to be caused by a sulfur attack in which service water was introduced into the steam generator inadvertently years ago. These indications are also volumetric in nature and are attributed to closely spaced small pits. Based on "look-back" assessments, there had been no recent growth observed in the two axial IGA indications. Here again it is believed that the 12RFO chemical cleaning made this degradation more visible.

A 100% full-length bobbin exam was utilized during 13RFO; therefore, escalation of the inspection sample was not required.

The freespan axial indications observed during 13RFO are listed below.

DBNPS 13 RFO 2002										
Axial Indications										
SG	Row	Tube	Ind	Volts	TSP	Inch1	Probe	Depth %TW (max.)	Ax Len	Deg. Mode
2A	66	68	SAI	0.35	04S	5.76	510UL / 520PP	51	0.48	Axial IGA
2A	151	4	SAI	0.48	15S	7	510UL / 520PP	29	0.71	Groove IGA
2A	151	4	SAI	0.14	15S	6.04	510UL / 520PP	1	0.63	Groove IGA
2A	151	11	SAI	0.2	15S	5.1	510UL / 520PP	1	0.66	Groove IGA
1B	22	93	SAI	0.51	15S	-2.33	510UL / 520PP	28	2.2	Groove IGA
1B	23	94	MAI	0.15	15S	-1.99	510UL / 520PP	24	0.71	Groove IGA

1B	72	60	SAI	0.43	06S	29.66	510UL / 520PP	56	0.67	Axial IGA
1B	134	1	SAI	0.18	15S	-1.48	510UL / 520PP	0	0.23	Groove IGA
1B	150	19	SAI	0.12	UTS	-19.78	510UL / 520PP	51	0.2	Groove IGA
	510UL=Bobbin Coil			SAI=Single Axial Indication						
	520PP=Plus Point Probe			MAI=Multiple Axial Indications						

Severed Plugged Tube

As a result of the TMI-1 event where a plugged tube severed and impacted neighboring tubes (refer to Nuclear Regulatory Commission (NRC) Information Notice 2002-02), the DBNPS deplugged and inspected:

(a) 19 B&W/FTI Alloy 690 roll plugs that were installed as a replacement for original Alloy 600 plugs. Originally, 20 tubes had their upper tube end plugs removed and replaced, and were not stabilized. These tubes could have potentially let water become trapped in the tightly sealed tube. This plug replacement was in response to discovery of cracking of Alloy 600 tube plugs. None of these tubes were in the Steam Generator periphery drilled TSP locations. One of these tubes was pulled full length during 11RFO and displayed no trapped water or swelling. An inspection of the 19 remaining tubes by deplugging the upper tube end, inspecting for water and performing eddy current profileometry was performed. None of these tubes were found to be swollen. Following the inspection, these 19 tubes were stabilized and rolled plugs were reinstalled.

(b) 28 Alloy 690 roll plugs fabricated by B&W. This population of tubes were the result of rerolling 33 plugs after one cycle of operation as a required action due to concerns over potential loose plugs. This action could have also lead to water being trapped in the tube if the re-rolled plugs were leaking prior to the plug re-roll activity. Of these tubes, 5 are stabilized in the upper span and not at risk to damage adjacent tubes. An inspection of the 28 unstabilized re-rolled plugged tubes, by deplugging the upper tube end, inspecting for water and performing eddy current profileometry was performed. Of these tubes, one tube (A-79-105) was found to have been filled 80% with water, but was found not to be swollen. This most likely means the plugging hardware was leak limiting, not leak tight. None of these tubes were found to be swollen. Following the inspection, these 28 tubes were stabilized and rolled plugs were reinstalled.

Although not identified as a tube population at risk for swelling, 7 tubes plugged with ABB/CE hardware were to be deplugged to have their stabilizers replaced to support a power uprate. Five of these tubes were deplugged and had their stabilizers replaced. One of the ABB/CE stabilizers was not removed due to difficulties removing the entire rolled plug so this tube was caged with stabilized tubes and a welded plug was installed over the hot leg tube end. Another tube had its ABB/CE stabilizer removed, however due to a dent, the larger Framatome stabilizer would not fully insert. This tube was also surrounded with stabilized plugged tubes as an alternate stabilization method. This action removes all ABB/CE OTSG stabilizers from being relied on to protect the primary pressure boundary.

Subsequent to the completion of 13RFO steam generator inservice inspection activities, in April 2002, Duke Power Company identified a plugged tube which had severed in their Oconee Unit 1 steam generators. Destructive examination of the severed tube indicated that the tube severed as a result of intergranular attack originating from the inside diameter of the tube. There were no obvious indications of fatigue, transgranular degradation, or significant ductile tearing. The severed tube was one of 12 tubes instrumented with thermocouples during the first cycle of operation (early 1970s). The tubes in which these thermocouples were installed were plugged at the cold leg end while the hot leg end remained open. Following the first cycle of operation, the thermocouples were removed and the tubes were plugged at the open end. At the time of plugging, there was water in the tube.

The findings at Oconee Unit 1 have some notable differences from the severed plugged tube found at TMI (refer to NRC Information Notice 2002-02). The tube at TMI severed at the upper tubesheet (UTS), was swollen along the entire length of the tube, and failed as a result of fatigue; whereas, the tube at Oconee, severed at the lower tubesheet (LTS), was not swollen, and failed as a result of intergranular attack.

Based on findings at Oconee Unit 1, the DBNPS staff reviewed the results from the eddy current inspection for the portion of tubing in the first span (i.e., from the secondary face of the LTS to the first tube support plate). No volumetric indications were identified next to a plugged tube. (Volumetric indications could be indicative of tube wear as a result of a severed tube.) The data for dents, manufacturing burnishing marks, and non-quantifiable indications were also reviewed. This data review identified one indication next to a plugged tube which warranted additional investigation. This tube had an indication approximately 22.5-inches above the secondary face of the LTS. Inspection with a rotating probe equipped with a plus point coil did not reveal any degradation. The raw eddy current data was reevaluated and confirmed the original findings.

The DBNPS staff also reviewed historical records to determine if foreign material had been left in any plugged tube or if any tube has been operated with only one end of the tube plugged. The review for foreign material was conducted since foreign material may have contaminants which could lead to tube degradation such as was observed at Oconee Unit 1. The review to determine if only one end of a tube was plugged was conducted since the tube that severed at Oconee was operated for one cycle with only one end of the tube plugged. The review of plant history did not identify any tubes that were operated with only one end of the tube plugged. The review of historical records did not identify any tubes plugged with foreign material (e.g., stuck probes, etc.) inside.

Visual Welded Plug Examination

Prior to 13RFO, the DBNPS steam generators had 36 construction-era welded Alloy 600 plugs in both steam generators. These plugs were manufactured by B&W and were manually welded to the tube end and tubesheet. Cracks were detected in the weld of two of these construction-era welded plugs in steam generator 1-B. The apparent cause of the cracks was determined to be a manufacturing defect of an undersized weld combined with a lack of weld fusion. Both affected plugs were removed, the tubes were inspected, and then the plugs were replaced with remotely welded Alloy 690 plugs.

During the inspections following removal of the construction-era welded plugs, holes were identified in these tubes. These holes were inserted prior to tube plugging and were located approximately 2 inches below the UTS secondary face. The tubes were plugged by the manufacturer since they did not pass initial acceptance testing. In total, 18 tubes were plugged after potentially installing a hole in the tube. To address the potential that these tubes could sever from a circumferential flaw initiating from the hole location, a plan was developed for stabilizing all tubes surrounding these plugged tubes. Stabilization involves inserting a metal cable/rope into the tube such that if the tube severs it will not impact other tubes. For 16 of the 18 tubes, all tubes surrounding the plugged tubes were stabilized (such that if one of these tubes severed it would impact a tube which was stabilized). For the remaining two inner-bundle tubes, the DBNPS did not stabilize all of the tubes surrounding the plugged tubes with the "hole" because of surrounding tubes being previously plugged for other reasons and not stabilized. For one of these two tubes, two surrounding tubes were not stabilized; for the other tube, four surrounding tubes were not stabilized. Although not stabilized, these six tubes were previously plugged and analysis was performed to ensure that continued operation for the next cycle was acceptable. Stabilization of these six tubes is planned for the next steam generator inspection.

2. ***During a pre-inspection conference call between Nuclear Regulatory Commission (NRC) and Davis-Besse staff (refer to ML021410043), it was indicated that Davis-Besse would perform in-situ pressure testing of the tube in row 22, tube 93, in SG 2A. Discuss the criteria you used to determine which indications were in-situ pressure tested and the results of all in-situ pressure tests performed during the outage.***

The DBNPS 13RFO In-Situ Pressure Test Selection Document was developed consistent with the EPRI Steam Generator In Situ Pressure Test Guidelines, the EPRI Steam Generator Tube Integrity Assessment Guidelines, the EPRI PWR Steam Generator

Examination Guidelines and NEI 97-06. The tests were performed in accordance with the safety factors described in Draft Regulatory Guide 1.121 Revision 01. Defects identified by the Eddy Current examination were "best effort" sized for length, circumferential extent and percent through wall. Flaw voltage was also considered in the in-situ pressure test selection process. The defect types remaining, which were not bounded by limits defined in the In-situ pressure test selection document were evaluated by in-situ pressure testing. The structural limit calculations of the DBNPS In-Situ Pressure Test Selection Document fully considered all required uncertainties. Material property uncertainties and strength equation uncertainties were based on the EPRI Steam Generator Degradation Specific Management Flaw Handbook. Appropriate NDE degradation sizing uncertainties were obtained from the EPRI and Vendor Examination Technique Specification Sheet (ETSS) documents defined for use in the Davis-Besse Degradation Assessment document. The basic approach of the EPRI Steam Generator Degradation Specific Management Flaw Handbook was followed.

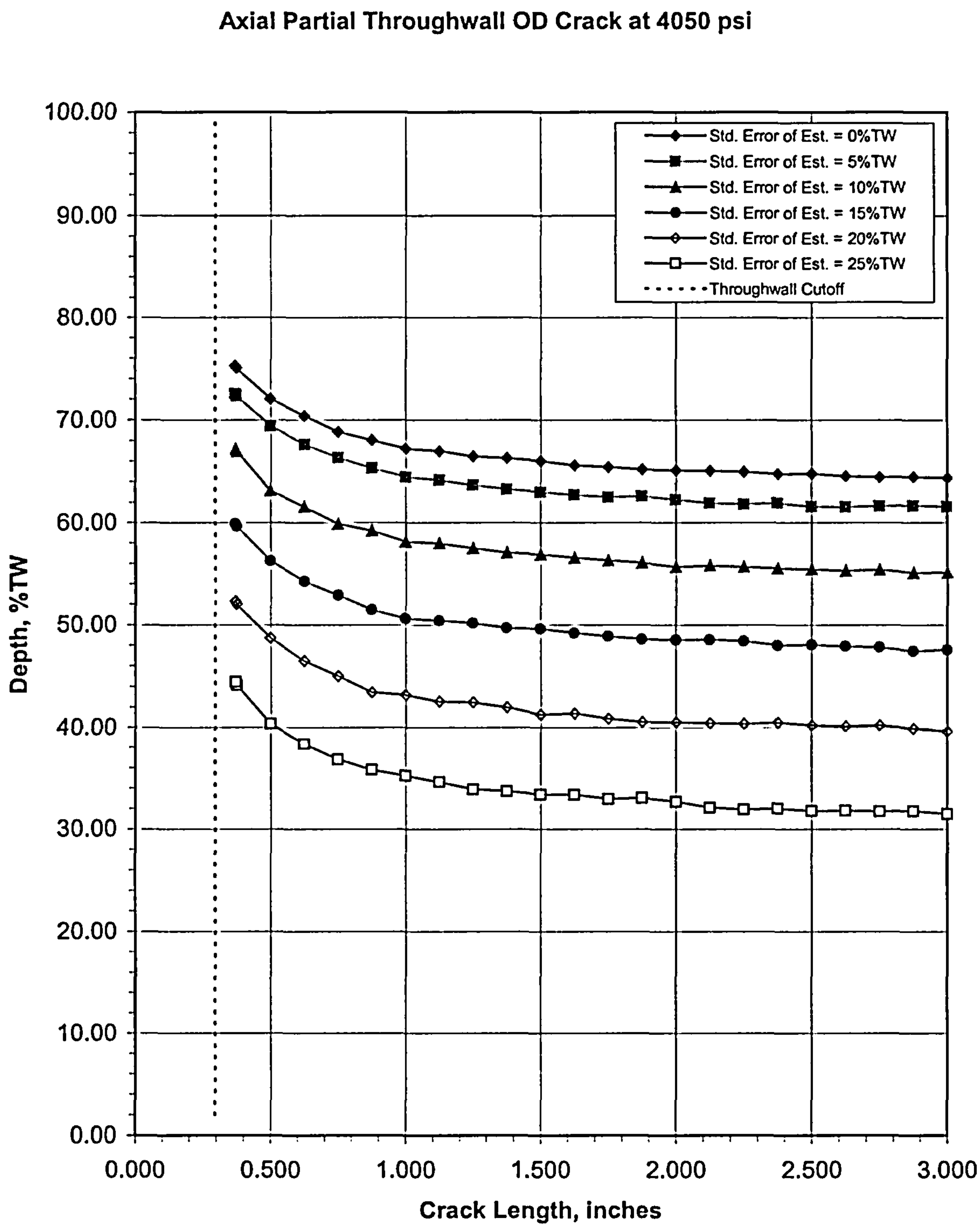
Condition monitoring limit curves were developed for through-wall axial and circumferential cracking, partial through-wall axial and circumferential cracking, volumetric degradation around the full tube circumference, and volumetric degradation around less than 135 degrees of the tube circumference. A degraded tube demonstrates acceptable structural margins when NDE measured lengths, depths and circumfrential extents result in a plotted point below the appropriate condition monitoring limit curve. Only those tubes which plot above the condition monitoring limit need be considered for in situ pressure testing for structural margin reasons.

A total of five indications in four tubes were in situ pressure tested. Three of these indications in two tubes were axially-oriented and were indicative of OD groove IGA. Another tested tube had an axial indication reported in the central region of the steam generator. This indication was located in the same region of the steam generator as the volumetric OD IGA indications attributable to the feedwater chemistry excursion that occurred in the mid-1980s. The other tested indication was a small axial indication located at a dent in the uppermost span. All of the tested indications were tested at pressures up to 3 delta-P (a test pressure 4550 psig) with no leakage.

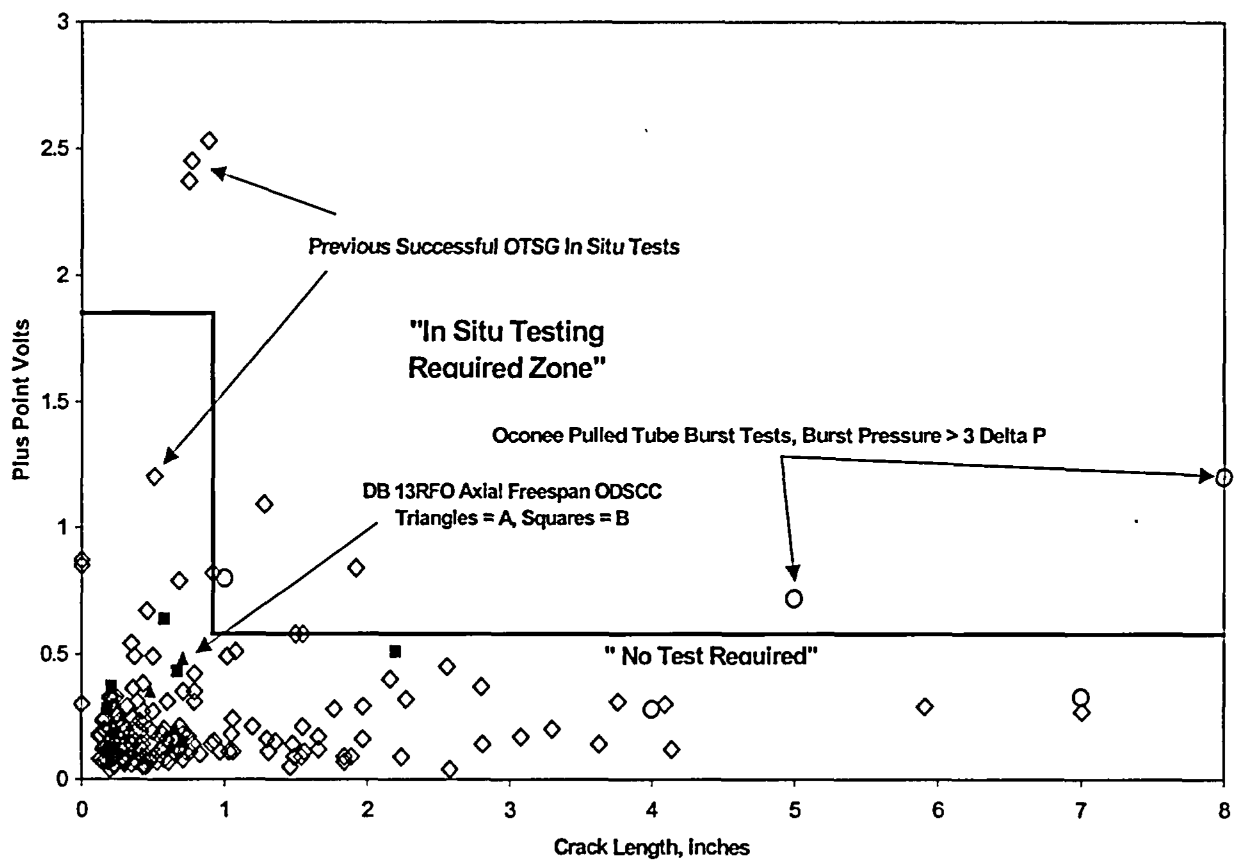
It should be noted that tube A-22-93 is an in-service tube and should not have been an in-situ pressure test candidate. Tube B-22-93 was in-situ pressure tested during 13RFO.

DBNPS 13 RFO 2002										
Indications In-Situ Tested										
SG	Row	Tube	Ind	PlusPoint Volts	TSP	Inch1	Probe	Depth %TW (max.)	Ax Len	Deg. Mode
2A	151	4	SAI	0.48	15S	7	510UL / 520PP	29	0.71	Groove IGA
2A	151	4	SAI	0.14	15S	6.04	510UL / 520PP	1	0.63	Groove IGA
1B	22	93	SAI	0.51	15S	-2.33	510UL / 520PP	28	2.2	Groove IGA
1B	72	60	SAI	0.43	06S	29.66	510UL / 520PP	56	0.67	Axial IGA
1B	123	66	SAI	0.24	UTS	-4.42	510UL / 520PP	12	0.58	Dent
	510UL=Bobbin Coil			SAI=Single Axial Indication						
	520PP=Plus Point Probe			MAI=Multiple Axial Indications						

The plus point depths recorded in the indication list is a flaw maximum depth whereas the condition monitoring curves for in-situ screening are based on structural controlling depth which has been demonstrated to be approximately 0.8 times the maximum flaw depth. The following curve is from the in-situ selection criteria for partial wall penetration axial flaws. For ODIGA/SCC, the worst depth standard error of 25 % was used.


Axial Partial Throughwall OD Crack at 4050 psi
Std. Error of Est. = 0%TW
Std. Error of Est. = 5%TW
Std. Error of Est. = 10%TW
Std. Error of Est. = 15%TW
Std. Error of Est. = 20%TW
Std. Error of Est. = 25%TW
Throughwall Cutoff
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Depth, %TW
0.000
0.500
1.000
1.500
2.000
2.500
3.000
Crack Length, inches

Plus point voltage screening was also used as a consideration for the in-situ selection based on historical in-situ and pulled tube burst results. The graph below compares plus point voltages and lengths of the freespan axial ODSCC degradation observed at the DBNPS with a database of previous successful in-situ tests for this type of degradation in other OTSG plants. By this measure it is seen that the severity of degradation at the DBNPS did not pose a threat to structural or leakage integrity. As a conservative measure, in-situ tests to the 3 delta-P limit with allowances for temperature differences and pressure gauge uncertainty were performed for 4 freespan axial ODSCC indications.



3. ***With respect to the inspections at dented locations, please address the following:***

a. ***Clarify whether the classification of "dents" in your report includes dents/dings at tube supports (including the tubesheets) and in the free span.***

The DBNPS only classifies OTSG tubing plastic deformation as denting. Dents are identified in any tube location where the Bobbin coil can identify and classify the deformation including tubesheets, supports and freespan regions. Dings are not an indication classification used at the DBNPS.

b. ***The number, location, and severity of your dents/dings.***

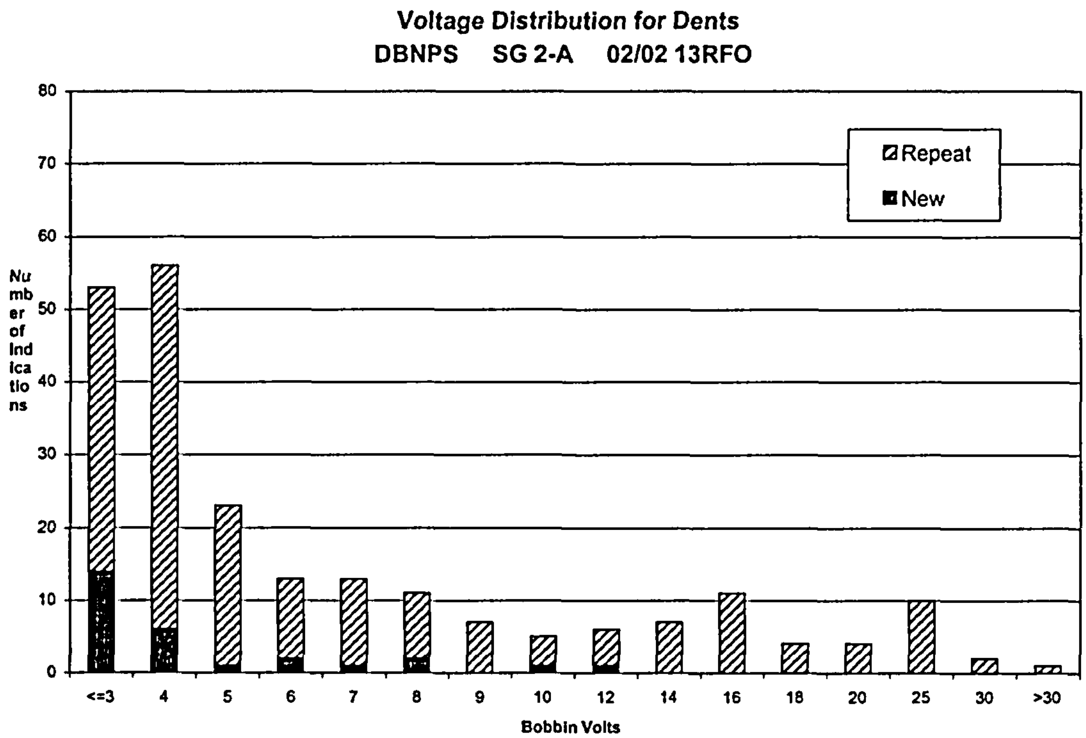
SG 2-A had 226 total (new and repeat) dents reported excluding dents in the deplugged tubes. New means dents that were reported for the first time. Three tubes with dent indications (DNTs) were removed from service for reasons unrelated to the dents. Of the remaining 223 dents, 18 were located at or above 14S.

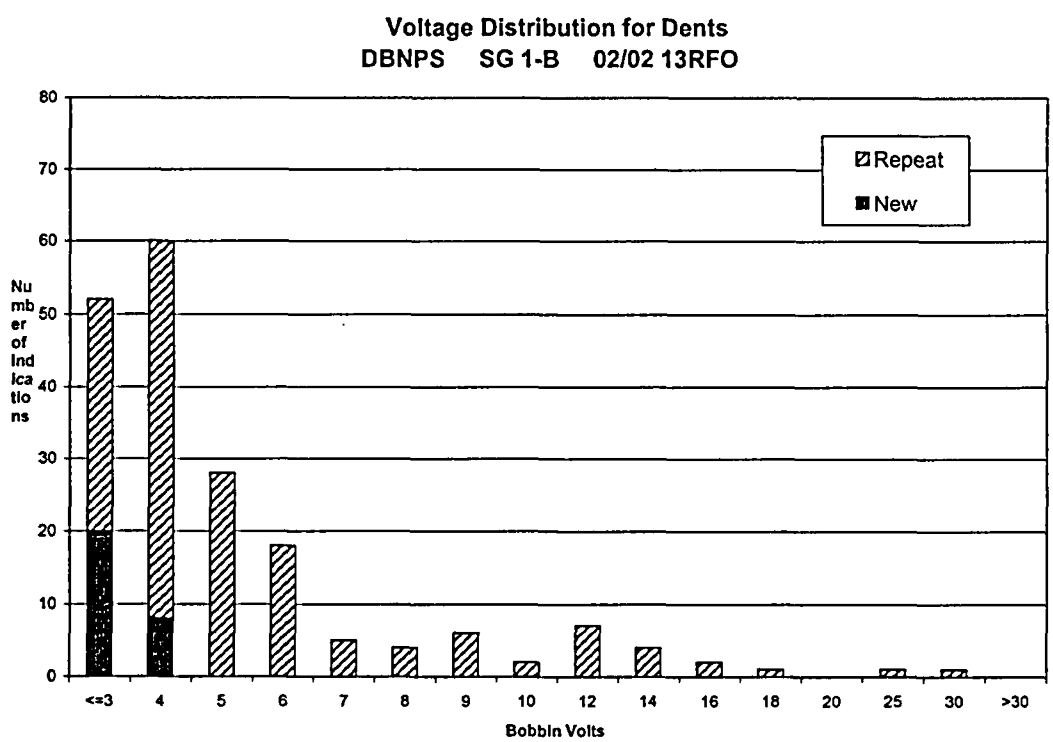
SG 1-B had 194 total (new and repeat) dents reported excluding dents in the deplugged tubes. 191 of these dents were reported with the bobbin coil. 3 other dents were reported with the pancake coil. Four tubes with DNTs were removed from service. Of the 190 remaining dents, 21 were located at or above 14S.

The dent location distribution identified during 13RFO was as follows:

Distribution of Dent Indications by bobbin coil exam		
DBNPS-1 02/02 13RFO		
Elev	OTSG 1-B	OTSG 2-A
UTSM	7	8
UTSF	6	8
15S-UTSF	5	2
15S		
14S-15S	3	
14S		
13S-14S	6	
13S		
12S-13S	2	
12S		
11S-12S	3	
11S		
10S-11S	14	
10S	7	
09S-10S	12	6
09S	1	
08S-09S		1
08S		1
07S-08S	1	
07S		
06S-07S	3	5
06S		1
05S-06S	1	1
05S		
04S-05S	1	
04S		
03S-04S	4	
03S	1	1
02S-03S	4	1
02S	3	
01S-02S	37	1
01S	3	
LTSF-01S	6	3
LTSF	8	175
LTSM	53	12
Total	191	226

The voltage distribution for dents during 13RFO was as indicated on the attached figures:


Voltage Distribution for Dents
DBNPS SG 2-A 02/02 13RFO
Repeat
New
Number of Indications
Bobbin Volts
0
10
20
30
40
50
60
70
80
<=3
4
5
6
7
8
9
10
12
14
16
18
20
25
30
>30


Voltage Distribution for Dents
DBNPS SG 1-B 02/02 13RFO
Repeat
New
Number of Indications
Bobbin Volts
0
10
20
30
40
50
60
70
80
<=3
4
5
6
7
8
9
10
12
14
16
18
20
25
30
>30

c. ***Confirm that your voltage normalization scheme for determining the size of dents is consistent with the standard industry approach.***

Per the DBNPS eddy current guidelines the bobbin probe is calibrated to 4 volts on a 20% flat bottom hole calibration standard. This calibration method is an industry standard.

d. ***Clarify your statement that "all dent locations" above the 14th tube support plate were inspected. What is considered a dent (i.e., is a voltage amplitude criteria used such that dents are reported when they exceed a certain voltage threshold)?***

Plastic deformation that causes a Bobbin coil amplitude of 2.5 volts or greater results in a dent classification. Rotating coil examination of all dent calls above the 14^{th} tube support plate were conducted during 13RFO. The 2.5 volt threshold is based on the eddy current technique specification sheet (ETSS) qualification for detection of OTSG tubing PWSCC.

e. ***For each flaw (if any) detected during the outage at a dented location, please indicate whether the flaw: (1) was initially found during the bobbin screening, (2) was only identified with a rotating probe, (3) was identified during the initial bobbin screening and confirmed with a rotating probe, or (4) was only identified with the bobbin after the rotating probe results were available.***

For each of the 4 dents identified as requiring repair during 13RFO, an NQI was reported from bobbin before being interrogated with a rotating coil probe. The special interest inspection, or dent inspection was then used to confirm the indication through plus point inspection.

f. ***Discuss how the 60 percent sample of dents below the 14th tube support was determined. For example, was it a random sample or were all dents above 5 volts examined with a rotating probe and the remaining sample was random? Discuss whether the original scope of the rotating probe examinations at the dents/dings was expanded based on the results. The staff notes that both stress and temperature affect a tube's susceptibility to stress corrosion cracking. As a result, a larger dent at a lower temperature may be as severe (from a stress corrosion cracking standpoint) as a smaller dent at a higher temperature (material properties being equal). Discuss how the inspection scope accounted for this.***

The DBNPS inspected a 60% sample of tubes with dents reported in the 100% bobbin inspections conducted during 12RFO and 13RFO that were located below the 14th tube support plate. Dents that were inspected with a rotating coil during 11RFO and 12RFO were excluded from the 60% sample selection. 20% random samples, which excluded the previous outage selection, had been performed during the past two outages so a 60% inspection completed a 100% sample in three cycles.

Escalation of inspections of the dents below the 14^{th} TSP that were 2.5 volts by bobbin coil or greater was to occur in the affected OTSG if one defect was found in a dent below 14S. During the initial inspection, expansion was to also be considered should dent cracking below the 2.5 volt threshold be discovered.

All repaired dents were located in the 15^{th} span. The DBNPS has not been observing active dent cracking below the 14^{th} support. All dents below the 14^{th} support have been inspected with rotating coil over the past 60 effective full power months (EFPM) (3 fuel cycles). Additionally all dent cracking observed during 13RFO was first identified as an NQI by bobbin inspection adding confidence to the detection of this damage mechanism.

g. ***Discuss the extent to which the bobbin probe is qualified to inspect dented/dinged regions exceeding a specific voltage threshold (e.g., 5 volts).***

The only industry qualification in effect for the bobbin probe at dented intersections is for axial PWSCC at less than 2 volt dents with 4 volts on a 20% standard ASME flat bottom calibration holes set at 2.75 volts in Mix 1 which equates to 2.5 volt dents with OTSG normalization. Though not formally qualified, the bobbin probe has some capability to detect degradation at larger voltage dents as verified through field experience.

4. ***Discuss whether any exceptions were taken to the Electric Power Research Institute guidelines during the 2002 inspection and summarize the technical basis for each of these exceptions/deviations.***

At the time of the 13RFO OTSG examination there were four exceptions to the EPRI guidelines that were being taken. These exceptions followed the requirements for taking exceptions to NEI 97-06 including conducting peer reviews of the exceptions.

Exception Number 1 was against the EPRI PWR Steam Generator Examination Guidelines Revision 5. This deviation documented not including the "False Call" rate in the Site Specific Performance Demonstration (SSPD) Grading Criteria. The EPRI Guidelines requires "the number of reported false calls be no more than 10% of the total number of unflawed grading units" when grading a Qualified Data Analyst (QDA) test. For 13RFO, the 10% false call criteria was not used.

A SSPD is given to assure that OTSG data is presented and tested on by all analysts. The primary purpose of these tests are to assure that flaws are detected by the analysts. Not imposing false call criteria assures a higher Probability of Detection (POD) for the individual QDAs. The DBNPS believes that additional indication calls by an analyst results in a more conservative position and helps assure a safe and reliable inspection process.

Exception Number 2 was against the EPRI PWR Steam Generator Examination Guidelines Revision 5. This deviation documented the acceptability of following the DBNPS Technical Specification requirements for inspection escalation if tube end eddy current indications were discovered rather than those specified in the EPRI PWR Steam Generator Examination Guidelines.

The EPRI Guidelines requires an inspection of 100% of an area that has been identified with an active damage mechanism. During 13 RFO upper tube end rotating coil inspection, escalation criteria followed the DBNPS Technical Specification 4.4.5.2.c escalation requirements rather than the EPRI Steam Generator inspection guideline escalation requirements to preclude unnecessarily escalation to a 100% inspection. The assessment of acceptability of this approach was based on conservative assessment of leakage from roll transitions and tube ends using bounding estimates of end of cycle flaw populations from a C-3 inspection category result for these two flaw types.

No credit was taken for reduction in mass flow rate due to differences between accident and test density. Additionally credit was not taken for reduction in flow due to two-phase flow. It was also assumed that for each tube end crack found there was an additional undiscovered crack in this tube end, and the number of flaws is increased based on POD limitations and included a 20% increase in flaw population during the cycle.

It was determined that leakage performance criteria would not be exceeded if a C-3 inspection category were encountered for the upper tube end exams when accounting for leakage from all mechanical repairs as well as tube end defects.

Exception Number 3 was against the EPRI PWR Steam Generator Examination Guidelines Revision 5. This deviation documents the acceptability of following Lower Tube Sheet (LTS) region inspection recommendations defined by criteria developed by the B&W Owners Group (BWOG) rather than the EPRI Steam Generator inspection guideline requirements. This inspection criteria defined a rotating coil exam that augmented the bobbin inspection to sample 500 tubes contained in the limiting Oconee defined sludge pile region in each OTSG.

In review of the issue, there appeared to be two major contributors to previous industry experience with bobbin detection failure in the LTS. The presence of sludge appears to interfere with the detection capability and the presence of sludge initiated denting appears to initiate tube degradation in this region of suspected poor bobbin detection.

Based on the DBNPS dent profile and pre-chemical cleaning sludge pile being smaller than that of those plants used to develop the recommendations of this review, a smaller radius could be defined for the DBNPS region of concern. This region ranges from a radius of 22" to 30" and follows the shape of a cardioid due to the DBNPS pre-chemical cleaning sludge pile profile, however, for 13RFO the Oconee sludge pile region was followed for this inspection. The Oconee sludge pile area encompassed a larger area of the lower tubesheet than the previous DBNPS sludge pile region and was conservatively used as the defined area of suspected degraded probability of detection (POD) requiring additional inspection.

If indications with plus point voltages of greater than 1.8 volts were found outside the defined radius, the scope of the inspection would be increased to encompass the radius of the most distant indication of significant voltage.

Based on BWOG experience, plus point inspections of the LTS region was conducted from 4 inches above to 16 inches below the LTS. The acquisition above the LTS encompassed the top of the sludge pile.

It was concluded that it was justified to use BWOG experience rather than to use EPRI Steam Generator inspection guideline requirements to define the region of the LTS where rotating coil augmented inspections would be performed.

Exception Number 4 was against the EPRI PWR Secondary Water Chemistry Guidelines Revision 5. This deviation documented not following the portion of chemistry Action Level 3, specifically the requirement to: "...Regardless of the duration of the excursion into Action Level 3, the plant should be taken to hot or cold shutdown..."

Literal compliance with the recommendation may not have been the best response if feedwater sodium exceeds the 5 PPB Action Level 3 limit for brief periods. Unnecessary plant shutdown, cooldown and transients may be more damaging to the OTSGs than continued operation after a short duration chemistry transient. Initiation of a plant shutdown due to a short-term sodium spike would result in additional sodium release from secondary side components including the steam generators, high pressure (HP) turbine and reheaters due to changing steam conditions. This would expose the steam generator tubes to a higher integrated sodium load.

Each feedwater sodium excursion is to be evaluated on a case-by-case basis to determine the best course of action to limit the integrated exposure to sodium.

Short-term feedwater sodium increases as a result of redistribution of sodium within the steam and feedwater cycle. With appropriate plant action to identify the source and limit the total sodium ingress, adequate protection would be provided and OTSG tube integrity would not be impacted. Redistribution of sodium within the steam and feedwater cycle is not a sodium ingress, but a re-equilibration of sodium within the system in response to changing steam quality, temperature and steam generator level. Sodium tends to concentrate in the dry steam portion of the steam generators, the Wilson line in the HP turbine and at the dry-out line within the reheaters.

Power reduction would result in an additional release of sodium from the steam and feedwater system that would result in an overall increase in integrated sodium exposure to the steam generator tubes. Confirmation of the increase in sodium levels as redistribution or as an ingress event permits conservative decision making to occur with respect to shutdown or power reduction.

5. ***During a pre-inspection conference call between NRC and Davis-Besse staff (refer to ML021410043), it was indicated that cracks were located in two construction-era welded plugs. Discuss the results of the inspection you performed on the plugs, including any additional information on the cause of the cracks identified in the construction-era welded plugs.***

A Visual examination (VT-1) performed during the 13RFO on the seal welds of all installed welded tube plugs of the OTSGs found multiple radial indications in one tube plug weld and found one radial indication in another tube plug weld.

The affected plugs were located near the center region of the primary face of the lower tubesheet of the 1-B OTSG. This particular plug design includes a weld that connects and overlays the original tube and tube to tubesheet weld to the tubesheet clad. These plugs were pre-service manufacturing welded plugs that had been in service since 1977 and had experienced approximately 50 full heat-up and cool down cycles.

The weld at plug location B-92-55 appeared to contain an irregularity. There existed a small area of cold lap at the weld stop that appeared to be the indication initiation point. The weld at location B-127-65 appeared to have a larger weld stop crater where several indications appeared to have initiated. The affected welds also appeared to be slightly smaller than other similar welds. These observations tended to suggest that original manufacturer defect was causal or as a minimum a significant contributing factor.

These plugs were not located in limiting stress regions of the OTSGs; therefore, fatigue was not considered to be the dominant mechanism. Other similar plugs were located in higher stress regions of the OTSG and displayed no evidence of cracking. Additionally, these plugs were located in the cold leg and therefore not considered to be at high risk for

Primary Water Stress Corrosion Cracking. Other similar plugs were located in the hot leg and displayed no evidence of cracking.

The primary to secondary leakage during the previous cycle was small. At the DBNPS, no previous cracks in OTSG plug welds were found. The two failed welded plugs were machined out and replaced with new welded plugs.

6. ***Discuss whether any loose part signals and/or wear due to loose parts was discovered during the outage. If a loose part was detected by eddy current, discuss whether the presence of the parts were visually confirmed and whether the parts were removed from the SG. If the parts were not removed, summarize the technical basis for leaving these parts in service.***

During the 13RFO exam, there were no confirmed loose parts indications detected by eddy current. The only confirmed wear was at TSP intersections due to typical support wear. During the 13RFO exam the secondary side remained sealed and no secondary side visual exam was performed. The last secondary side exam was performed during 12RFO as part of the OTSG chemical cleaning activities. No loose parts wear was observed from either visual or eddy current exam during 12RFO as well.

7. ***In Tables 1 and 4, it was indicated that "all tubes with flaw-like indications" were inspected with a rotating probe. Clarify what is meant by "all tubes with flaw-like indications".***

Flaw-like indications from bobbin are reported either as %TW for TSP wear, NQI, ADI or manufacturing burnishing mark (MBM) to encompass all locations in the tube. All %TW, NQI and ADI indications receive a plus point inspection each outage. The MBM indications are established from the 8RFO or earlier data, receive an initial plus point inspection for confirmation and are monitored for change using the bobbin afterwards. Change for MBMs is based on the judgment of the resolution analysts. Any MBM that is identified with change is inspected with plus point.

For example, were all tubes with indications at support structures inspected with a rotating probe?

All tubes with bobbin indications (%TW, NQI, ADI) in any region of the tube were inspected with plus point. Additionally a sample of the dents was also inspected with plus point.

How were bobbin indications determined to be non flaw-like?

Non flaw-like bobbin indications are those that are well understood like dents, bulges, design geometry, secondary side deposits and secondary side structures.

For manufacturing indications (frequently called burnishing marks) and freespan differential signals (if any) discuss the scope and results of any rotating probe examinations at these locations.

Twelve MBMs were inspected with rotating coil with no service related degradation reported.

How is an indication determined to be manufacturing-related (e.g., traceable back to baseline)?

The MBM indications are characterized to be shallow volumetric indications with bobbin, plus point and pancake coils and are confirmed to be present in the earliest available data which is from the 8RFO or earlier inspections with no change since then.

If a manufacturing indication changes over time (since the baseline inspection), discuss whether any rotating probe examinations are performed and the criteria used to determine whether or not a change in the bobbin signal occurs (e.g., 0.1 volt change, phase angle change of 3 degrees, etc.).

If an MBM is noted to have changed it is inspected with plus point probe/pancake coil. Determining whether or not a change has occurred is the responsibility of the resolution analyst.

For any criteria used to determine if a signal exhibits little or no change, discuss how the criteria was determined (e.g., was test repeatability evaluated for these types of indications such that the criteria would identify a signal change when the change was greater than normal test repeatability).

Determination of whether there is a change is the responsibility of the resolution analyst because it requires more than a simple application of measurable parameters. Signal shape, appearance and multi-frequency response must also be considered when evaluating change.

8. *In Tables 2 and 5, the location of flaws detected are listed. Discuss the point of reference for the measurements. For example, does 14S-0.73 indicate the indication is 0.73-inch below the bottom, top, or center of tube support 14S? If from the middle of a tube support, please indicate the thickness of the support.*

Tube Support Plates are 1.5 inches thick. The reference location used in the OTSGs is from the centerline of the support; therefore, 0.76 inches is outside support plate and 0.75 inches is at the edge of support plate.

9. *Address the criteria used to plug/repair defects. For example, were all crack-like indications plugged/repaired upon detection? Were wear indications sized and left in service, etc?*

At the DBNPS, plug-on-detection is performed on all suspected flaws other than wear. The rotating pancake coil is currently used to perform tube to tube support plate wear sizing. This is the only technique that is used to allow wear flaws to remain in-service. All other volumetric and crack like flaws are repaired regardless of phase angle or voltage. This is due to the fact that the DBNPS has not employed any Alternative Repair Criteria and has not accepted any industry sizing qualifications other than wear indications. All of the wear indications measured with the plus point coil during 13RFO were less than the 40% TW Technical Specification repair limit.

10. *Address whether the performance criteria were met for the previous cycle of operation. Discuss whether any new damage mechanisms were detected during this outage other than IGA associated with grooves (i.e., groove IGA).*

The only damage mechanism considered new for the DBNPS was the discovery of groove IGA.

Condition monitoring evaluations were performed for all observed degradation at the DBNPS. Structural integrity was demonstrated via analyses and verified by in-situ testing to meet required performance criteria. Burst strengths were demonstrated to meet 3 delta-P requirements at a probability of 0.95 at 50% confidence. Axial load requirements were demonstrated to be met at the same margin. All uncertainties were included, NDE uncertainty, material property uncertainty and uncertainties in burst pressure and axial load equations. Leakage integrity was verified against required performance criteria and was verified and quantified for all degradation mechanisms. The analysis and methodologies used to verify that condition monitoring was satisfied are contained in the 12RFO and 13RFO Condition Monitoring and Operational Assessment (CMOA) reports.

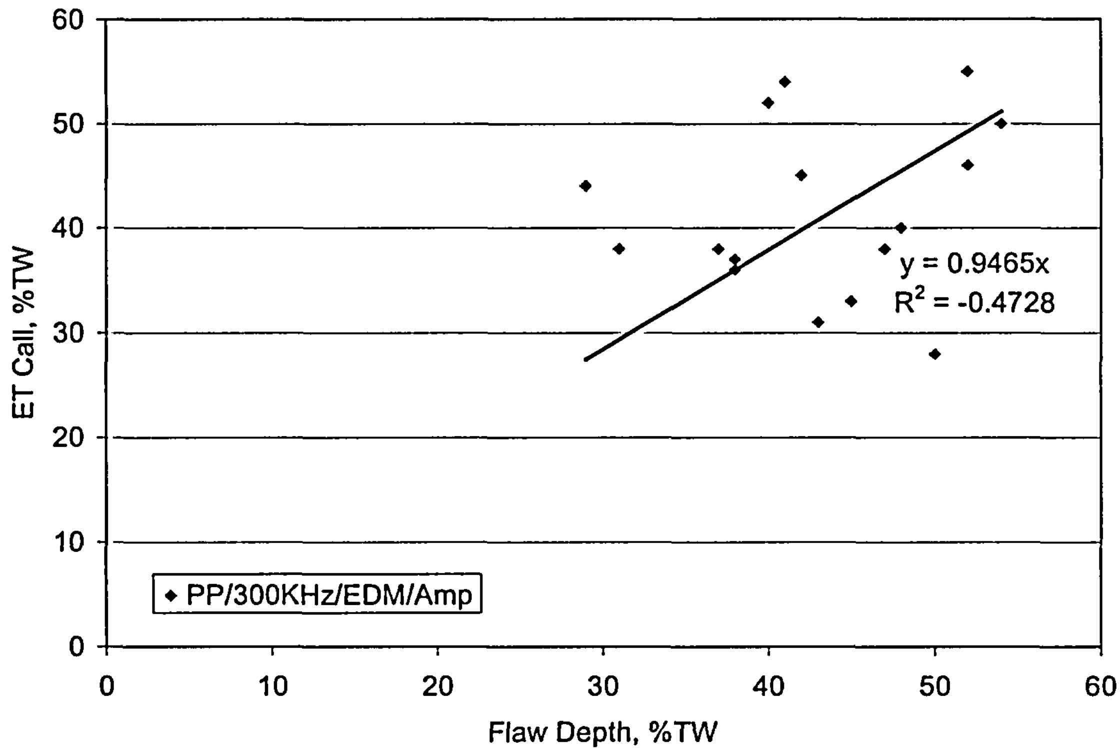
11. Define a "tube end anomaly".

Per the DBNPS eddy current guidelines, a tube end anomaly is an axially oriented indication that has been identified in the portion of the tubing that is above the carbon/clad interface of the tubesheet. This designation is used only if there is no evidence of the indication extending into the carbon steel region of the tubesheet.

12. Several of the volumetric indications are approximately 60 percent through-wall. Were these indications left in service during the prior inspection? If not, discuss the reason for the apparent high growth rate of the indications (i.e., from non-detected to 60 percent through-wall in one cycle). Discuss any implications of these findings to your operational assessment.

In 1998, tube A-79-68 in OTSG 2-A was deplugged, eddy current inspected, and then pulled for destructive examination. This tube had been plugged during 8RFO. A previous feedwater chemistry excursion in OTSG 2-A is believed to have led to several hundred tubes with eddy current indications that were plugged during 8RFO. Destructive examination of tube A-79-68 revealed secondary side volumetric IGA. Small volumetric patches of IGA were distributed from the 4th to the 9th support plates. These patches of IGA were not associated with grooves or scratches. Selected regions of tube A-79-68 were burst test tested. Measured burst strengths were approximately 8000 psi and higher. This high margin relative to a 3 delta P value is consistent with a maximum axial length of degradation on the order of 0.26 inches and maximum depths of about 55% TW.

Based on the type of defects (patch IGA) present on the OD of the pulled tube, an effort to develop an approved eddy current sizing technique was attempted with the use of the pulled tube data. However, that ability to provide repeatable and accurate depth measurement of this damage prevented the successful development of a sizing qualification for this damage. Low flaw voltage signals were especially problematic in the ability to accurately size this damage.



It was concluded that the low voltage volumetric indication depth measurements were not reliable and that the plus point voltage values were a more reliable indicator of tube integrity. The center bundle volumetric indications that are being detected have much smaller voltage amplitudes than that of the pulled tube study. The typical voltage range for the volumetric flaws identified during 13 RFO were typically less than 0.3 volts. Whereas the pulled tube study voltages ranged from 0.95 volts to 0.26 volts.

The 12RFO chemical cleaning likely resulted in the removal of tube deposits that were preventing previous detection of these low voltage amplitude flaws. The DBNPS staff believes that these indications are not rapidly growing or initiating and that they are not a significant integrity threat.

These indications were addressed in the 13RFO CMOA under the assumption that a Monte Carlo simulation of growth measurement provides a reasonable assessment of the growth behavior of this damage. The result of this analysis identified that Operational Assessment requirements for this damage mechanism were met for Cycle 14.

COMMITMENT LIST

The following list identifies those actions committed to by the Davis-Besse Nuclear Power Station (DBNPS) in this document. Any other actions discussed in the submittal represent intended or planned actions by the DBNPS. They are described only for information and are not regulatory commitments. Please notify the Manager – Regulatory Affairs (419-321-8450) at the DBNPS of any questions regarding this document or any associated regulatory commitments.

COMMITMENT	DUE DATE
None	N/A